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October 17, 2022

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Submitted by email to rbares@utah.gov and rwood@utah.gov

Subject: Comments Regarding Advance Notice of Rulemaking for Natural Gas-Fired Boilers, Steam Generators, and Process Heaters

Dear Mr. Bares and Mr. Wood:

The Utah Petroleum Association ("UPA") and the Utah Mining Association (jointly, "the Associations") appreciate the opportunity to comment on the Advance Notice of Rulemaking for Natural Gas-Fired Boilers, Steam Generators, and Process Heaters ("draft Boiler Rules" or "Boiler Rules"). Thank you for extending the comments due date to October 17, which allowed us to provide more thoughtful and detailed comments towards developing rules that will be technically and economically feasible for our member company operations.

UPA is a statewide oil and gas trade association established in 1958 representing companies involved in all aspects of Utah's oil and gas industry. UPA members range from independent producers to midstream and service providers, to major oil and natural gas companies widely recognized as industry leaders responsible for driving technology advancement resulting in environmental and efficiency gains. Five member companies each operate a petroleum refinery in the Northern Wasatch Front ozone nonattainment area ("NWF"). Additionally, UPA member companies operate oil and gas production and midstream facilities within the Uintah Basin ozone nonattainment area. Thus, our member companies have an interest in air quality and air emissions controls throughout Utah.

The Utah Mining Association was founded in 1915 and serves as the voice of Utah's mine operators and service companies which support the mining industry. The member companies operate hardrock, industrial mineral, and coal mines throughout the State of Utah. The Utah Mining Association has an interest in air quality in support of the communities in which our member companies operate and air emissions controls in Utah.

The Associations and our member companies support rules that will be cost effective towards improving air quality and that are technically and economically feasible to

implement. For example, many of our member companies implemented emission reductions to meet technically and economically feasible Best Available Control Technology ("BACT") for the Serious $PM_{2.5}$ State Implementation Plan ("SIP"). Furthermore, petroleum refineries are now supplying Tier 3 gas, thus providing significant benefit to local air quality, considering both $PM_{2.5}$ and ozone. Similarly, we support this rulemaking with modifications needed to ensure technical and economic feasibility and added detail for clarity and completeness. In general, the draft Boiler Rules need broader recognition that not all boilers are the same; the Boiler Rules need a pathway for larger and more complex industrial boilers to demonstrate compliance.

The concept of a rule that would phase in over a period of time as facilities need to change burners for operational or maintenance reasons appears like a simple but effective means to phase in a rule for greatest cost effectiveness and the least amount of operational difficulty, which the associations appreciate. This may very well be so for smaller commercial and multi-family residential boilers where a new burner can easily be installed, or the boiler swapped with a new off-the-shelf commercial boiler. However, due to the complexity of our member company operations and their boiler systems, this approach raises concerns for our member companies as described in detail in these comments. Further, the member company Best Available Control Technology ("BACT") analysis submitted for the Serious $PM_{2.5}$ State Implementation Plan ("SIP") provide further evidence of much higher costs and, in some cases, lack of technical feasibility.

We understand the rules to be based on swapping a standard or a low NOx burner ("LNB") for an ultra-low NOx burner ("ULNB") whenever a burner needs to be replaced. This is not technically viable for many large industrial scale boilers as discussed in detail in our comments below. To address this, we ask that the rules include provision for a case-by-case analysis like the BACT analysis performed for permits. It would be best to include this option for all boilers to ensure feasibility in all cases.

Furthermore, for UPA member companies operating their boilers on refinery fuel gas, burner manufacturers have confirmed that ULNB technology will not achieve 9 ppm, also explained below in more detail. There may be other instances where 9 ppm cannot be achieved on industrial boilers, especially with specialty equipment that may be required for certain manufacturing operations.

Although the title of the rule includes process heaters and steam generators, the rule language does not include these types of equipment within the applicability. We understand UDAQ's stated intent to be to change the title of the rule to apply to boilers only and to leave the applicability language within the Boiler Rules as is, applying only to boilers and not to other equipment mentioned in the draft Boiler Rule title. We support this approach with additional case-by-case paths to compliance as described below. If the rule were to apply to process heaters, the number of applicable units would increase significantly with an exponential increase in the diversity of existing equipment that could be subject to retrofits and a variety of additional operating constraints to work within. In this case, we would have additional comments not included in this letter. We would need significantly more time to consider the ramifications of broader applicability.

Recommendation #1: The Boiler Rules should include provisions for case-by-case analysis to set case-by-case NOx limits that are technically and economically feasible for the individual operation.

Three concerns support the need for this recommendation:

1. Burners cannot be easily swapped for burners of different designs.

2. Large industrial boilers have complexities and constraints that drive costs up such that the cost analyses for the draft Boiler Rules significantly under-represent actual costs anticipated.

3. The level of 9 ppm NOx may not be technically feasible with current burner technology (or possibly at all) in many types of industrial boilers including those in petroleum refineries.

We discuss each of these concerns in detail with recommendations.

Although our examples of the need for this provision center on larger industrial boilers, we have not done an exhaustive search of smaller boilers within our member companies to assess specific examples of the need for the provision. Therefore, we recommend including the provision in both Boiler Rules to ensure technical and economic feasibility in all cases.

<u>Recommendation #1.1: The draft Boiler Rules anticipate replacing a single existing burner with a single ULNBs whenever one or more burners are replaced. However, swapping burners poses design, safety, and operating problems in industrial boilers that could require significant re-engineering of the entire firebox at substantially higher cost. This justifies the addition of case-by-case feasibility analysis to the Boiler Rules.</u>

Burners in large industrial boilers cannot simply be swapped out for ULNBs without extensive engineering analysis and possible extensive redesign. Boilers and burners in the petroleum refining industry are subject to three consensus Recommended Practice ("RP") standards published by the American Petroleum Institute ("API") to ensure safety, reliability, and operability:[1]

- API RP 535, "Burners for Fired Heaters in General Refinery Services" – covers effect of fuel gas hydrogen content on NOx emissions, flame stability, flame characteristics, retrofit considerations, maintenance, burner testing, and numerous other pertinent topics.

- API RP 538, "Industrial Fired Boilers for General Refinery and Petrochemical Service" – covers important design and safety aspects such as burners and burner management systems, igniters and igniter management systems, burner arrangements, protective systems, CO boilers, safety switches, trips, alarms, and numerous other topics.

- API RP 560, "Fired heaters for general refinery service" – covers numerous design details.

Each of these API RP standards has extensive detail, all of which must be considered and addressed in boiler design, maintenance, and operation, and must be reconsidered for burner redesign. In some cases, petrochemical companies also follow API standards.

[1] API standards are developed under API's American National Standards Institute accredited process, ensuring that the API standards are recognized not only for their technical rigor but also their third-party accreditation which facilitates acceptance by state, federal, and increasingly international regulators. For more detail about API standards, see https://www.api.org/products-and-services/standards.

ULNBs have a longer flame pattern than other burners. These longer flames can impinge on boiler tubes, flames from other burners, refractory protecting the shell of the boiler firebox, and tube hangers within the firebox, thus subjecting the boiler parts to unacceptable damage, safety concerns, and operability and reliability problems. For example, a communication from the burner manufacturer John Zink to a member company states, "Flame is expected to be 40-50% longer than current [burner design] (~23Ft now), which would exceed your furnace dimensions (30.17Ft furnace depth)." The HollyFrontier Serious $PM_{2.5}$ BACT report provides additional information:

> *An additional consideration with retrofitting existing heaters to LNB or ULNB is the flame pattern. LNB and ULNB generally produce a longer flame in the fire box which can extend to contact process piping or the convection section of the heater. Contact with process piping can result in coking of the inside of the process pipes which results in a loss of heat transfer and eventual plugging. Flame extension into the convection section can result in heat transfer not consistent with engineered design resulting in process coking, inadequate heat transfer, heater box temperature, and loss of process control.*[2]

ULNBs may require more space than existing burners of standard or LNB design and may not fit within the existing firebox burner area, thereby requiring replacement of the entire boiler unit or de-rating the boiler due to fitting in fewer burners, an unacceptable choice from an operating standpoint. The required redesign would decrease cost effectiveness significantly and may not be feasible due to operating schedules and space available to construct the new unit while the old one operates. It would require rerouting piping and instrumentation at added cost, not included in the cost analysis, and would need to be estimated on a case-by-case basis. Disruptions to the operating schedule must be considered as lost profit opportunities within the cost analysis. For example, the HollyFrontier BACT Report states:

> *An analysis was performed to evaluate the technically feasibility and cost effectiveness of upgrading existing process heaters with LNB or ULNB. In conversations with representatives from John Zink, when upgrading the existing units to LNB or ULNB, the floor of each heater box would have to be reconstructed to insert the LNB or ULNB which are typically longer and wider than the existing burners. Also, LNB and ULNB have a lower heating duty per burner than traditional burners; therefore, in some cases, will result in a need for additional burners to achieve the firing rate needed for the process application. Most heaters at HollyFrontier are not designed to accommodate additional burners and would need to be reconstructed all together. If additional burners cannot be added and the heater is not reconstructed, then a process rate decrease would need to take place.*[3]

Thus, burners cannot simply be replaced with alternate design burners in many industrial boilers.

<u>Recommendation #1.2: The incremental burner cost estimates for the draft Boiler Rules do not represent the well-thought-out estimates provided for the $PM_{2.5}$ BACT analysis, and allowance must be made for case-by-case cost estimates as part of determining the appropriate NOx levels in specific situations.</u>

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[2] "Best Available Control Measure Analyses HollyFrontier's Woods Cross Refinery" prepared for HollyFrontier Woods Cross Refining LLC and prepared by Meteorological Solutions Inc. a Trinity Consultants Company, April 2017 ("HollyFrontier BACT Report"), p. 4-17. Report available at https://deq.utah.gov/air-quality/control-strategies-serious-area-pm2-5-sip (accessed on October 11, 2022).

[3] HollyFrontier BACT Report, p. 4-17.

We understand that the cost estimates for the draft Boiler Rules consider replacing only a single burner with ULNB technology at the time that a burner requires replacement, and thus the cost estimates for the rule rely on incremental costs for single burner changeout compared to in-kind replacement costs for the burner. UDAQ cost estimates were all based on small boilers with the largest at only 6.7 MMBtu/hour,[4] not reflective of many of our member company industrial operations. On the other hand, our member company boilers may be ten to twenty times larger, with significant differences in design, operation, and safety considerations. As explained above, single burners cannot typically be replaced with ULNBs in industrial boilers without re-engineering the entire firebox.

The cost evaluation provided for the draft Boiler Rules, based on the incremental cost to replace a single burner with lower NOx technology, simply does not apply when the burner replacement triggers a much larger modification of the entire boiler. The cost evaluation would need to consider the entire redesign, as the Serious $PM_{2.5}$ BACT analyses do where applicable.

Thus, the incremental cost estimates provided for the rulemaking vary by orders of magnitude from the actual costs that our member companies expect to face to meet the requirements of the draft Boiler Rules. Our member companies expect the costs to meet the draft Boiler Rules to be more in line with cost estimates they provided for the $PM_{2.5}$ rulemaking because the retrofits will be similar, i.e., often requiring complete redesign of the boiler. The $PM_{2.5}$ BACT cost estimates are more appropriate for large industrial boilers due to the numerous safety and operability requirements of these operations that prohibit simply swapping burners.

In 2017, Chevron reported the cost to retrofit two of its boilers at $55,000 and $43,000 per ton of NOx reduced, costs that consider the site-specific requirements and constraints.[5]

In cases where LNBs, ULNBs (that may not meet 9 ppm), or even Selective Catalytic Reduction ("SCR") have already been installed on a boiler, the current performance of these units with respect to NOx emissions was not factored into the cost effectiveness determination for the draft Boiler Rules, and the cost effectiveness of reducing NOx even further will be lower. In comments provided by the Western States Petroleum Association ("WSPA") for Best Available Retrofit Control Technology ("BARCT") for petroleum refinery boilers and heaters in development of South Coast Rule 1109.1, WSPA showed that incrementally lower NOx levels carry a dollars per ton cost effectiveness several times greater than the cost effectiveness of the control.[6] UDAQ recognized this in their Stationary Source BACT Report for the Serious $PM_{2.5}$ SIP, where they show escalating costs per ton to reduce NOx from boilers with lower current NOx levels. The

[4] Utah Department of Environmental Quality, "Best Available Control Technology (BACT) Analysis: Ultra-Low NOx Burners on Natural Gas Fired Boilers" by John Persons, Environmental Engineer II, September 27, 2002.

[5] Letter, Christina King, HES Manager, Chevron Products Company Salt Lake Refinery, to Mr. Martin D. Gray, Manager, Utah Air Quality Board, April 26, 2017. Attachment entitled "Boiler #1 FI 1001, Boiler #2 F11002, and Boiler #4 FI 1004 BACT Analysis," table with "Summary of ULNB Costs For Boiler #5 F11005 and Boiler #6 F11006," p. 8. Available at https://deq.utah.gov/air-quality/control-strategies-serious-area-pm2-5-sip (accessed on October 11, 2022).

[6] Letter, Patty Senecal, Senior Director, Southern California Region, WSPA, to Michael Krause, Manager, Planning and Rules, South Coast Air Quality Management District, August 4, 2021.

UDAQ analysis also recognizes the effect of remaining useful life of the boiler and the size of the boiler on the cost per ton.[7]

Furthermore, UDAQ's own cost analyses for its own stationary source $PM_{2.5}$ BACT analyses far exceed the costs provided in the memo for larger industrial sources, especially for those units upgrading from burners that are not standard burners and for units requiring SCR. UDAQ's analysis recommends case-by-case BACT, similar to our request here as an option in the Boiler Rules. The following excerpts from the report illustrate this:[8]

> *The economic feasibility analysis demonstrates that retrofit options and boiler replacement could both be cost effective options depending on the boiler size, age, and hours of operation. DAQ found through this analysis that SCR was not a cost-effective feasible option.*
>
> *Retrofitting or replacing existing low-NOX boilers with ultra-low NOX boilers proved to be cost prohibitive for the scenarios evaluated. Retrofit costs start at $14,097 per ton of NOX removed and replacement costs start at $29,489.*
>
> *DAQ recommends good combustion practices as BACT for the existing boilers operating at major sources within the nonattainment area. An evaluation to determine whether retrofitting or replacing boilers with low-NOX or ultra-low NOX burners is economically feasible should be conducted on a case-by-case basis.*

Table 5 of the UDAQ Stationary Source BACT Report provides detail on incremental costs to upgrade from LNB or ULNB to 9 ppm and an SCR retrofit. LNB replacement costs all exceed $9,000 per ton of NOx reduced and ULNB replacement costs exceed $8,500, thus costs are in excess of the costs provided for the draft Boiler Rules. The table shows ULNB replacement to go from 30 ppm to 9 ppm with costs exceeding $29,000 and SCR costs exceeding $19,000.[9]

It is possible that the relatively low costs per ton of NOx removed reported in the UDAQ staff analyses for the draft Boiler Rules may be due at least in part to the relatively small boilers evaluated, less than 7 MMBtu/hr. The University of Utah reports costs of more than $100,000 per ton of pollutant removed in a boiler of 87.5 MMBtu/hr but does not report any particular operating constraints for the boiler.[10]

Additionally, SCR may not be technically feasible in some cases. For example, Big West Oil provided the following information in their Serious $PM_{2.5}$ BACT analysis:

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[7] See Table 5 in "BACT for Various Emission Units at Stationary Sources" DAQ-2018-007161, located at https://documents.deq.utah.gov/air-quality/pm25-serious-sip/DAQ-2018-007161.pdf (accessed on October 9, 2022) ("UDAQ Stationary Source BACT Report") (p. 59).

[8] Appendix A, "BACT for Various Emission Units at Stationary Sources" DAQ-2018-007161, located at https://documents.deq.utah.gov/air-quality/pm25-serious-sip/DAQ-2018-007161.pdf (accessed on October 9, 2022) ("UDAQ Stationary Source BACT Report"), each of the three quotes are on p. 40.

[9] See Table 5. "Summary of Cost per Ton of NOX ($/ton) Removed Continuous Operation (8,760 hours/year)", UDAQ Stationary Source BACT Report, p. 44.

[10] See UCHWTP Boiler NOx analysis in "$PM_{2.5}$ Serious Nonattainment SIP BACM Analysis" prepared for the University of Utah, Salt Lake City, Utah, prepared by Trinity Consultants, April 2017, p. 3-10. Report available at https://documents.deq.utah.gov/air-quality/pm25-serious-sip/DAQ-2017-005321.pdf (accessed on October 11, 2022).

> *The BACT technology review showed potential additional control technologies including SCR, flue gas recirculation (FGR), [Wet Gas Scrubber - WGS], and an [Selective Non-Catalytic Reduction – SCNR]. However, the boilers have insufficient space for installing SCR, FGR, WGS, or SNCR; therefore, they are technically infeasible.*[11]

Proctor and Gamble provided the following information about technical infeasibility in their Serious $PM_{2.5}$ BACT analysis:

> *An ULNB most commonly uses an internal induced draft to reach the desired emission limitations. Due to this induced draft, an ULNB cannot handle a quick change in load to achieve the desired operational flexibility necessary for the varied products and change overs in the paper making operation. . . . P&G reviewed potential replacement burner options with an emission rate of 9 ppm NOx or less that would also meet the same process demands as the current Paper Machine Boilers. Due to the different types of products from the paper machines, the Paper Machine Boilers must have ample turndown capabilities to adjust the amount of steam. Due to the turn down requirements, P&G was unable to find a burner that would meet this requirement at a lower emission rate.*[12]

Again, we emphasize that since application of current generation ULNBs to existing industrial boilers could require complete boiler redesign, the $PM_{2.5}$ BACT cost and technical feasibility analyses provide a more appropriate feasibility evaluation for industrial boilers than the single incremental burner analyses provided by UDAQ.

<u>Recommendation #1.3: The 9 ppm NOx is not feasible in all situations; case-by-case feasibility analysis should be allowed within the Boiler Rules as a means to determine an appropriate technically and economically feasible NOx level for an individual boiler.</u>

Sustained operation at 9 ppm NOx has not been proven to be practicable in large refinery boilers. For example, a John Zink communication to a member company states, "*Retrofitting your current [low NOx type] to a different ultra-low NOx burner technology that can fire both [natural gas] and [refinery fuel gas] it <u>is not an option</u> . . . NOx is not expected to be achieved. We estimate approximately 15 to 17 ppm at the best with FGR [flue gas recirculation].*" [emphasis added]

Another member company reports consulting with another burner manufacturer, Zeeco, who advises that 9 ppm will not be possible for <u>*any*</u> burner firing on refinery fuel gas with <u>*any amount of hydrogen*</u>. They only see that kind of performance out of their best burners when firing 100% natural gas in a relatively cool firebox.[13]

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[11] "Best Available Control Technology Evaluation - Utah $PM_{2.5}$ State Implementation Plan" report prepared for Big West Oil Company by Environmental Resources Management; April 2017, p. 10. Report available at https://deq.utah.gov/air-quality/control-strategies-serious-area-pm2-5-sip (accessed on October 9, 2022).

[12] "$PM_{2.5}$ Serious Nonattainment SIP BACM/BACT Analysis" prepared for The Procter and Gamble Paper Products Company, Box Elder, Utah, and prepared by Trinity Consultants, April 2017 ("P&G BACT Report"), pp. 3-20 and 3-21. Report available at https://documents.deq.utah.gov/air-quality/pm25-serious-sip/DAQ-2017-006104.pdf (accessed on October 11, 2022).

[13] As a matter of economics, environmental protection, and practicality, refineries must use their excess gas as fuel gas and cannot substitute natural gas in lieu of refinery fuel gas. Depending on the refinery

Furthermore, the Chevron $PM_{2.5}$ BACT report provides the following information in its NOx BACT options for Boilers #5 F11005 and #6 F11006:

> *ULNBs, the "next generation" burner after the Low NOx Burners (LNBs), alter the air to fuel ratio in the combustion zone by staging the introduction of air to promote a "lean-premixed" flame and by means of an internal flue gas recirculation. This results in lower combustion temperatures and reduced NOx formation. While the boilers were installed with what could have been considered ULNB technology at the time, further advances in burner design make lower emissions possible. In new installations, NOx emissions as low as 0.01 Ib/MMBtu have been achieved. However, based on discussions with relevant vendors, for a retrofit application a value of approximately 0.025 Ib/MMBtu is more realistic.*[14]

0.025 lb/MMBtu equates to approximately 21 ppm, far higher than the proposed level of 9 ppm.

The Serious $PM_{2.5}$ BACT report for HollyFrontier presents a table of BACT results for process heaters and boilers nationwide ranging in size from 10 to <100 MMBtu/hr and a second table for equipment greater than 100 MMBtu/hr. The tables show NOx for units with ULNBs mainly ranging from 0.025 to 0.040 lb/MMBtu, which equates to a range of approximately 20 to 35 ppm NOx.[15]

A report prepared by the Fossil Energy Research Corporation developed for the South Coast rulemaking identifies only two manufacturers of ULNBs that may achieve the levels of NOx sought in the draft Boiler Rules within petroleum refineries, but neither have conducted full scale tests on large boilers.[16]

The FERCO report also identifies that the South Coast Rule 1109.1 intends to require a variety of different technologies including ULNBs, SCR, and other technologies, rather than only ULNB burner technology used for the cost estimates provided by UDAQ. As noted above, these other technologies may or may not be technically or economically feasible and must be evaluated on a case-by-case basis as was done for the $PM_{2.5}$ BACT analysis. If installed, they would add considerable cost.

Furthermore, South Coast Rule 1109.1 allows until 2034 for implementation, more than ten years from promulgation, in contrast to the phased implementation of the draft Boiler Rules that may be triggered at any time. Member companies with facilities in the South Coast jurisdictional area report they may undergo complete redesign of their boiler facilities, which is well beyond the cost-

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configuration, refinery fuel gas contains varying amounts of hydrogen and of heavier components, neither found in natural gas with refinery fuel gas concentrations.

[14] Letter, Christina King, HES Manager, Chevron Products Company Salt Lake Refinery, to Mr. Martin D. Gray, Manager, Utah Air Quality Board, April 26, 2017. Attachment entitled "Boiler #1 FI 1001, Boiler #2 F11002, and Boiler #4 FI 1004 BACT Analysis" P. 6. Available at https://deq.utah.gov/air-quality/control-strategies-serious-area-pm2-5-sip (accessed on October 11, 2022).

[15] See Table 4-6 and 4-7, "BACT Determinations for N0X from Process Heaters and Boilers with Heat Capacities between 10 and <100 MMBtu/hr" and "BACT Determinations for NOx from Process Heaters and Boilers with Heat Capacities >100 MMBtu/hr" respectively, HollyFrontier BACT Report, p. 4-14.

[16] "South Coast Air Quality Management District Rule 1109.1 Study Final Report," prepared for South Coast Air Quality Management District, prepared by Fossil Energy Research Corporation (FERCO), November 2020 ("FERCO Report"). See discussion on pp. 3-1 to 3-2.

effectiveness of this UDAQ rule. In fact, the South Coast NOx requirements were developed over the course of decades, implementing successively lower NOx requirements through extensive dialogue and regulatory negotiation between the regulatory agency and the regulated community.

Moreover, we do not consider SCR to be an acceptable alternative where ULNB technology cannot be deployed or cannot attain 9 ppm under actual conditions.

If SCR were to be required by the UDAQ Boiler Rules, ammonia emissions would increase, the effect of which would need to be evaluated and considered for wintertime $PM_{2.5}$. The FERCO Report further states that, "Careful SCR design and frequent tuning of injected ammonia and flue gas will be required in all cases," to meet the South Coast limits for refinery equipment.[17]

A member company reports that installing SCR on their several boilers is not feasible due to lack of space and/or because the flue gas is not hot enough for SCR to work properly on a given boiler.

Procter and Gamble reported the following in their Serious $PM_{2.5}$ BACT report:

> *There are a few other technical considerations with regards to use of an SCR on the boilers. The need for turndown or modulation of the Paper Machine Boilers load will make it difficult to maintain the suggested removal efficiencies in practice due to the inconsistent exhaust stream. . . . The exhaust stream will require additional temperature from the exhaust stream to meet the SCR operating temperature requirements (minimum of 480°ΔF], This increase in exhaust temperature would require an additional combustion device, also increasing NOx, S02, and $PM_{2.5}$ emissions. . . . Due to the necessary turndown requirements of the Paper Machine Boilers, an SCR is considered technically infeasible for these units.*[18]

Procter and Gamble reported a cost of $165,250 per ton of NOx removed to reduce NOx from just 10 ppm to 9 ppm on the new utility boilers of their Project Maple.[19]

During the UPA meeting with UDAQ on September 23, there was some discussion about limits even lower than 9 ppm being required in the South Coast and San Joaquin Valley rules. These lower levels and, as explained above at times even 9 ppm, often require SCR to achieve. Also as explained above, SCR would require an entirely different cost and feasibility analysis which must be done on a case-by-case basis and must consider associated operating costs and other design and siting constraints. Ultimately, SCR may not be technically feasible or cost effective. For example, Chevron reported costs of $120,000 and $94,000 per ton of emissions reduced to retrofit two of its boilers with SCR.[20]

Some member company facilities both within and outside of Utah have SCR on boilers that cannot meet 9 ppm NOx including some with low NOx burners in combination with SCR. Limits for these

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[17] FERCO Report, p. 3-12.
[18] P&G BACT Report, p. 3-21.
[19] P&G BACT Report, p. 3-22.
[20] [20] Letter, Christina King, HES Manager, Chevron Products Company Salt Lake Refinery, to Mr. Martin D. Gray, Manager, Utah Air Quality Board, April 26, 2017. Attachment entitled "Boiler #1 FI 1001, Boiler #2 F11002, and Boiler #4 FI 1004 BACT Analysis," table with "Summary of SCR Costs For Boiler #5 F11005 and Boiler #6 F11006," p. 10. Available at https://deq.utah.gov/air-quality/control-strategies-serious-area-pm2-5-sip (accessed on October 11, 2022).

boilers are near 20 ppm and in at least one case, 40 ppm. The cost effectiveness to achieve 9 ppm in these cases, would be far less than the cost effectiveness provided for the draft Boiler Rules, if 9 ppm could be achieved at all, and must consider the effect of ammonia slip on wintertime $PM_{2.5}$.

The Salt Lake City elevation above sea level of approximately 4200 feet will affect the ability to achieve the same NOx rates compared to sea level due to the lower partial pressure of oxygen, posing an additional barrier to achieving 9 ppm.

Some boilers may have air preheat, which may also make 9 ppm NOx impossible to achieve. Air preheat saves fuel by using the heat remaining in hot flue gas to preheat the combustion air, but it increases the NOx concentration in the flue gas, thus resulting in a tradeoff of efficiency and total amount of emissions versus concentration of emissions. This phenomenon occurs because of the formation of "thermal NOx" from the higher combustion temperatures caused by the air preheat.[21]

During periods of high turndown, fluctuating refinery fuel gas composition, and fluctuating heat input requirements typical in large industrial operations, NOx will fluctuate from the guaranteed level. Also, whenever a burner must be taken out of service for individual burner maintenance, the higher firing rate required of other burners could <u>increase</u> NOx emissions.

In summary, due to these many concerns including inability to replace a standard or LNB burner with an ULNB on a burner-by-burner basis, accurate costs for large industrial boilers, feasibility (or lack thereof) of achieving 9 ppm NOx, and unique characteristics of refinery fuel gas combustion, we request that a provision for case-by-case technical and cost feasibility analyses be included in the Boiler Rules for proposal.

Recommendation #2: The rule should apply only to those boilers burning pipeline quality natural gas and should include a corresponding definition of natural gas.

The rule contains no definition of natural gas, nor do UDAQ's definitions in its General Rules[22] include a definition of natural gas. In discussion with UDAQ staff, they did not articulate a clear definition and thought that it included all types of gas. The staff also referred to the definition of natural gas in 40 CFR Part 63 Subpart JJJJJJ ("Boiler MACT"). Boiler MACT has a very broad definition of natural gas that includes propane and mixtures with at least 70 percent methane.[23] Relying on this definition would not address our concerns about refinery fuel gas described here.

In general, the Associations do not consider the Boiler MACT definition of natural gas to be suitable for defining gas burned in boilers in a rule regulating NOx emissions. The Boiler MACT rule regulates HAP emissions and not NOx. The Boiler MACT definition does not clearly exclude refinery process gas. Refinery fuel gas has different characteristics for producing NOx than the other gases contemplated in the Boiler MACT definition. For example, refinery fuel gas often contains more hydrogen which burns very hot and increases thermal NOx formation. Reaching

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[21] See https://www.pollutiononline.com/doc/nox-emission-reduction-strategies-0001 (accessed September 26, 2022).
[22] See General Requirements, Definitions in R-307-101-2.
[23] See 40 CFR Part 63 Subpart JJJJJJ §63.11237.

9 ppm with ULNBs that burn refinery fuel gas does not have the same feasibility as with natural gas. Consequently, burner manufacturers will not guarantee 9 ppm NOx for refinery fuel gas.

For example, John Zink provided the following information to one Salt Lake City petroleum refinery:

> Our RMB burner technology is our burner of choice for single digit NOx application *(<9ppm). This would be a good fit for your boiler when firing [natural gas], but unfortunately it is not an option for your Refinery Gas (with current fuel blend containing hydrogen, nitrogen and other heavy hydrocarbons, **RMB burner will not work**).”* [emphasis added]

The rulemaking process in the San Joaquin Valley for Rules 4306 and 4320 recognizes the limitations of refinery fuel gas compared to natural gas and other design and operating issues discussed above:

> *The proposed Rule 4306 NOx limits for boilers and heaters at petroleum refineries are generally higher than limits for other boilers and heaters due to their design and operating conditions. In addition, refineries use a mix of natural gas and non-[public utility company] quality process gas to fuel their boilers and heaters. Process gas contains differing amounts of impurities, including hydrocarbons, which create additional NOx when combusted.*[24]

We recommend defining natural gas in a manner that describes only pipeline quality natural gas. South Coast rule 1109.1 provides a suitable definition:

> *NATURAL GAS means a mixture of gaseous hydrocarbons, with at least 80 percent methane (by volume), and of pipeline quality, such as the gas sold or distributed by any utility company regulated by the California Public Utilities Commiss*ion.

We recommend that UDAQ adapt this definition to Utah, include it in the rule, and make the rule applicable only to boilers burning natural gas.

Recommendation #3: The rule should include an expanded definition of “boiler” that is included wholly within the rule (rather than including reference to a definition in an unrelated rule), uses the Boiler MACT definition of boiler as a starting point, and includes additional appropriate exemptions for temporary boilers and refinery CO Boilers as well as other appropriate situations.

The only definition provided in the draft Boiler Rules is the definition of Boiler. The Boiler Rules refer to the Boiler MACT definition of boiler which states:

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[24] “Proposed Amendments to Rule 4306 (Boilers, Steam Generators, and Process Heaters – Phase 3) and Proposed Amendments to Rule 4320 (Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater Than 5.0 MMBtu/hr)” draft staff report, San Joaquin Valley Unified Air Pollution Control District, November 25, 2020 (“SJV Staff Report”), p. 18. Report available at https://www.valleyair.org/Workshops/postings/2020/12-17-20_r4306-r4320/DraftStaffReport.pdf (accessed on October 11, 2022).

> *Boiler means an enclosed device using controlled flame combustion in which water is heated to recover thermal energy in the form of steam and/or hot water. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. A device combusting solid waste, as defined in § 241.3 of this chapter, is not a boiler unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Waste heat boilers, process heaters, and autoclaves are excluded from the definition of Boiler.*

The Boiler MACT provides a good start to a definition for the Boiler Rules and includes some necessary exemptions. The definition includes exemptions for waste heat boilers and process heaters, which we support retaining in the definition for the Boiler Rules. Waste heat boilers capture unused heat from equipment and are not themselves fired boilers with burners. Process heater applicability would bring in other concerns that we are not addressing in these comments based on our understanding of UDAQ's intent to include only boilers and not process heaters.

Nonetheless, we have three concerns with adopting the Boiler MACT definition of boiler without further modification in these Boiler Rules, and we provide recommendations to resolve the concerns.

<u>Recommendation #3.1: We recommend including the full boiler definition into the UDAQ rule rather than referring to it.</u>

First, reliance on a definition from a rule with an entirely different purpose, namely, to control hazardous air pollutants ("HAPs") rather than NOx, raises concerns about whether the definition could change in undesirable ways in the future without regard to its use in this rule intended to control NOx. For example, exemptions could be added or deleted from the Boiler MACT definition in the future without regard to what the exemptions mean to NOx emissions.

We recommend copying the Boiler MACT definition into the Boiler Rules. This has the added advantage of allowing changes to the definition appropriate to the Boiler Rules, as explained below.

<u>Recommendation #3.2: The boiler definition needs to be expanded to exempt temporary boilers. A definition of "temporary boiler" should be included in the rule.</u>

Temporary boilers may be brought in for short periods of time, up to 180 days, for various reasons. They are not likely to be available in the rental market at 9 ppm NOx or, if available, the cost may be far greater, a factor not considered in the cost analysis for the Boiler Rules, especially considering their short-term use. In communication with one large nationwide boiler rental company, they stated, "Our 20+ mmBtu steam boilers are rated for 30 ppm NOx on natural gas."[25] Considering the composition of refinery fuel gas as discussed above, we expect these rental boilers would have even higher NOx levels when burning refinery fuel gas instead of natural gas.

[25] Email communication from Alex Taylor, National Account Representative, WARE, to Marise Textor, October 9, 2022.

We also recommend including a definition of "temporary boiler" within the rules for clarity. The Boiler MACT includes a list of equipment not subject to the rule, including temporary boilers.[26] The New Source Performance Standard ("NSPS") for very large industrial, commercial, and institutional steam generating units, 40 CFR Part 60 Subpart Db, contains an exemption for temporary boilers[27] and a suitable definition in §60.41b that could be copied into the UDAQ boiler rules, as follows:

> *Temporary boiler means any gaseous or liquid fuel-fired steam generating unit that is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A steam generating unit is not a temporary boiler if any one of the following conditions exists:*
>
> *(1) The equipment is attached to a foundation.*
>
> *(2) The steam generating unit or a replacement remains at a location for more than 180 consecutive days. Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period.*
>
> *(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.*
>
> *(4) The equipment is moved from one location to another in an attempt to circumvent the residence time requirements of this definition.*

Although the Boiler MACT excludes temporary boilers,[28] the accompanying definition in Boiler MACT, while similar to that in NSPS Db, allows the temporary boiler to stay onsite for a year instead of 180 days and includes provisions for extension.[29] Thus, NSPS Db provides a more environmentally protective definition to copy into the Boiler Rules.

<u>Recommendation #3.3: We request an exemption for CO boilers from Fluid Catalytic Cracking Unit (FCCU) units at petroleum refineries and recommend including a definition of "CO boiler" in the Boiler Rules.</u>

FCCU CO Boilers pose an entirely different set of challenges to meeting 9 ppm NOx. CO Boilers receive part of their fuel as FCC regenerator off-gas which contains NOx unaffected by the burners:

> *Most NOx emissions from the COB are due to the oxidation of reduced nitrogen compounds entering the COB in the catalyst regenerator off gas. Low NOx Burners (LNB) in the COB have no effect on fuel-based NOx formation, and therefore are not considered further for analysis.*[30]

[26] See 40 CFR Part 63 Subpart JJJJJJ, §63.11195(h).
[27] See 40 CFR §60.40b(m).
[28] See 40 CFR Part 63 Subpart JJJJJJ, §63.11195(h).
[29] See "temporary boiler" definition in 40 CFR §63.11237.
[30] Section 4.3.2 of Best Available Control Technology Analysis, Tesoro Salt Lake City Refinery, Prepared for Tesoro Refining & Marketing Company LLC by BARR, April 2017 ("April 2017 BARR $PM_{2.5}$ BACT

The boiler definition in South Coast Rule 1109.1 includes the statement, "For the purpose of this rule, boiler does not include CO Boilers." We recommend exempting CO Boilers by including a similar statement within the boiler definition for the UDAQ rule.

The Boiler Rules should include a definition of CO Boiler. South Coast Rule 1109.1 includes the following definition, which could be copied into the Boiler Rules:

> *CO BOILER means a Unit that is fired with gaseous fuel with an integral waste heat recovery system used to oxidize CO-rich waste gases generated by the FCCU.*

Recommendation #4: Definitions of "construction", "modification", "reconstruction", and "certification" need to be added to the rule.

<u>Recommendation #4.1: The definitions of "construction" and "modification" included in UDAQ Rules may not support the intended purpose of the Boiler Rules and a new definition of "construction" at least should be added to the Boiler Rules.</u>

With no definition of "construction" or "modification" included in the Boiler Rules, the next place to look would be elsewhere within the UDAQ rules. UDAQ's General rule includes definitions that each rely on an increase in emissions.[31] We do not believe these definitions support the intent of the Boiler Rules.

We recommend incorporating a definition of "construction" into the Boiler Rules. One example that could be copied into the rules is the definition from NSPS:

> *Construction means fabrication, erection, or installation of an affected facility.*[32]

<u>Recommendation #4.2: No definition has been provided for "reconstruction" and one should be included in the Boiler Rules that incorporates key concepts in the "reconstruction" definitions of NSPS and MACT rules.</u>

Neither the draft Boiler Rules nor the UDAQ General Rule include a definition for "reconstruction". A definition should be included to prevent any misinterpretation. The definition provided in the NSPS relies on the reconstruction project cost exceeding 50% of the capital cost to build an entirely new facility and on technical and economic feasibility to meet the standards provided in the applicable NSPS.[33] Similarly, the definition provided in the MACT also relies on the 50% test and on it being technically and economically feasible to meet the applicable standard.[34]

We recommend adding a definition of "reconstruction" to the Boiler Rules that incorporates these key concepts of the NSPS and MACT definitions, namely the 50% test and technical and economic feasibility.

Report". Report available at https://deq.utah.gov/air-quality/control-strategies-serious-area-pm2-5-sip (accessed on October 11, 2022).

[31] See R307-101-2.

[32] Definition from 40 CFR Part 60 §60.2.

[33] See 40 CFR Part 60 §60.15.

[34] See 40 CFR Part 63 §63.2.

Recommendation #4.3. No definition for “certify” or “certification” has been provided and one needs to be included.

A key concept of the Boiler Rules is certification of ULNBs to meet a NOx emission rate of 9 ppm.[35] But the draft Boiler Rules include no definition or explanation of the meaning of “certification” or “certify.” What would be entailed in a certification? Would a simple manufacturer quote of expected NOx emissions be sufficient? What would be needed to turn the quote into a “certification”? What if the quote of anticipated NOx emissions level was based on an example fuel gas composition but the composition changes over time?

Recommendation #5: The number of burners replaced in the applicability threshold of the Boiler Rules should be increased from a single burner to 50% of the burners in the boiler, at least for the larger boilers with multiple burners.

The South Coast Rules 1109.1 and 1146.1 apply the new NOx limits when 50% of the burners within a boiler are changed, not when changing a single burner as in the draft Boiler Rules.[36] As explained above, it may not be feasible to replace a single burner with an ULNB, especially in large industrial boilers with multiple burners. UDAQ has not explained why it chose the lower threshold for changing burners.

Given the engineering requirements posed by the safety, reliability, and operability issues, the 50% threshold would be more appropriate, at least for larger industrial boilers where re-engineering and re-design may be required. Setting the threshold at 50% of the burners in the boiler would reduce unnecessary case-by-case analysis and numerous instances of associated agency review for individual burner replacements and would reduce repetitive work that does not add value to the overall goal of better air quality.

Recommendation #6: The 15-minute averaging time should be removed from the design NOx level and the header should be changed to remove “emission limit”.

Based on our discussions with UDAQ staff on September 23, 2022, we understand the 9 ppm NOx and 15-minute averaging time to be design averages but not an emissions limit or emissions compliance period. Therefore, the 15-minute averaging time should be removed from the design NOx level and the title should be changed to remove the phrase “emission limit.” We recommend replacing “Emission Limits and Requirements” in the title of R307-315-4 and R307-315-4 of the draft Boiler Rules with “Requirements”.

No basis or justification has been provided to substantiate the 15-minute averaging period for the design basis. The 15-minute period is not justified and is too short. South Coast Rule 1109.1, which the draft Boiler Rules were patterned after, have significantly longer averaging times for refinery boilers of 24-hour rolling average and interim limits based on 365-day rolling average.[37]

Moreover, ozone forms on a diurnal cycle and thus, averaging times in the Boiler Rules should not be substantially shorter than a day. The shorter averaging time provides no benefit to the

[35] See draft Boiler Rules R307-315-4(1) and (3) and R307-315-4(1) and (3).

[36] See South Coast Rule 1109.1(f)(2)(B) and (C) and (f)(4)(A) and South Coast Rule 1146.1(c)(6) and (e)(3).

[37] See Tables 1, 2, 3, and 5 of SC Rule 1109.1, adopted November 5, 2021.

intended pollutant control. Our member companies operate complex and dynamic operations that must accommodate changes in feedstock and operational changes and, in the case of petroleum refineries, changes in fuel gas composition, which are inconsistent with a 15-minute averaging period for NOx emissions.

Thus, a 15-minute averaging period is unlikely to provide improved ozone control over a 24-hour averaging period. In fact, it is unlikely to provide improved ozone control over a 30-day averaging period considering the very large number of boilers that will be subject to the Boiler Rules. We therefore recommend either dropping the 15-minute averaging or replacing it with something substantially longer.

Recommendation #7: Considering the complexities and feasibility concerns for large industrial boilers, we request an implementation timing of five years from date of the applicability trigger.

Considering all the various factors including the need to replace a burner on an operating unit for routine maintenance; the design, operation, and safety concerns associated with replacement burners; and length of time for major process equipment turnaround cycles (often three to five years),[38] we request that operators be given a minimum of five years to come into compliance with the Boiler Rules once burner replacements trigger applicability.

Compliance with the Boiler Rules could require redesigning the entire firebox, requires a planned turnaround, and could likely be the critical path for a turnaround. Our member companies need to have the ability to replace burners in kind on the run and, if they replace more than 50% in a period of time, only then should they trigger applicability. But they must be allowed sufficient time to plan, engineer, procure, and construct the required modifications to meet the Boiler rules. They need time to conduct a case-by-case feasibility analysis. In many cases, the extensive re-design could result in the need to modify the air construction permit as well, requiring additional time.[39]

Allowing a five-year period to come into compliance is consistent with South Coast Rule 1109.1, which allows a period of three years to come into compliance after *the agency issues* the air permit to construct.

Recommendation #8: We support the applicability of the rule to the full counties of the NWF and recommend extending the rule applicability to Utah County.

The Associations agree that the rule should apply to boilers located in the entire counties of Salt Lake, Davis, Weber, or Tooele Counties, even though the nonattainment area includes some partial counties. This will ensure that the nearby emissions from the partial counties outside the boundary of the NWF do not negatively impact the NWF and its ability to reach attainment.

We also recommend extending the rule applicability to Utah County, which comprises the Southern Wasatch Front ozone nonattainment area ("SWF"). We understand that EPA has

[38] Turnaround cycles may vary between three and five years depending on the process operation and needs of the operation. Shorter turnaround cycles increase the amount of associated lost profit.
[39] An example of the need to change the air permit would be if the facility uses the opportunity posed by required burner replacement and boiler redesign to incorporate other new design features or increased throughput, an opportunity that they should have the ability to pursue within the rule.

approved the SWF as having attained the 2015 ozone National Ambient Air Quality Standard ("NAAQS") by its attainment date.[40] However, the apparent year-to-date ("YTD") design value ("DV") for 2022 for the SWF appears to be 73 ppb, above the level of the standard:[41]

		4th High Values, ppb			YTD DV,
Monitor	Monitor Number	2020	2021	2022 YTD	ppb
Lindon	490494001	68	77	74	73
Spanish Fork	490495010	70	76	66	70

We fully understand that an official design value must be based on three full calendar years of data, after the data has been certified, and the data shown above for 2022 has not been certified nor is it based on the full calendar year. However, certification is unlikely to cause significant changes to the ozone measurements and considering that the fourth high for the full calendar year cannot be lower than the fourth high year-to-date, we consider the year-to-date design value to be a good approximation of the lowest value possible or likely for the official design value for 2022, a value that will ultimately be determined in 2023.

Although EPA approved the SWF as having attained by the attainment date, EPA's action does not constitute a redesignation and clearly the SWF is teetering on nonattaining air quality. With nonattaining air quality now, it may be difficult for UDAQ to develop the required maintenance plan showing attainment for the required 10-year period without additional emission reductions.

Furthermore, considering the proximity of Utah County and the SWF to the NWF, we fully anticipate that the photochemical model being developed by UDAQ may show an impact of Utah County emissions on the NWF. If the model shows Utah County to be contributing to NWF nonattainment, such a showing would support extending applicability of the Boiler Rules to Utah County.

Recommendation #9: At this time, the Boiler Rules have not been demonstrated to support the required ozone attainment demonstration. Considering this, we recommend that UDAQ take the necessary time to adequately address the issues of concern and recommendations outlined in this letter to ensure the final rules will be technically and economically feasible in all cases.

The Associations understand the need to reduce ozone precursor emissions to improve air quality. Nonetheless, as shown in **Figure 1**, over the past 15 years, reductions of NOx and VOC of 30% to 40% have not reduced ozone.[42]

[40] "Determinations of Attainment by the Attainment Date, Extensions of the Attainment Date, and Reclassification of Areas Classified as Marginal for the 2015 Ozone National Ambient Air Quality Standards" final rule; Federal Register, Volume 87, Number 194; October 7, 2022; p. 60897 ("DAAD").
[41] Fourth high values for 2020 and 2021 were obtained from EPA 2021 Design Value report for ozone, Table 5, Site Status, spreadsheet report available at https://www.epa.gov/air-trends/air-quality-design-values. Fourth high values for 2022 year-to-date were obtained by downloading daily data for ozone for the two monitors in Utah County at EPA Outdoor Air Quality website, https://www.epa.gov/outdoor-air-quality-data/download-daily-data, on October 10, 2022, which provided data through October 9, 2022.
[42] Emissions obtained from UDAQ statewide emission inventories located at https://deq.utah.gov/air-quality/statewide-emissions-inventories#section-2. As of this writing, 2017 is the latest year for which both EPA and UDAQ have provided a statewide emission inventory with emissions for all sources.

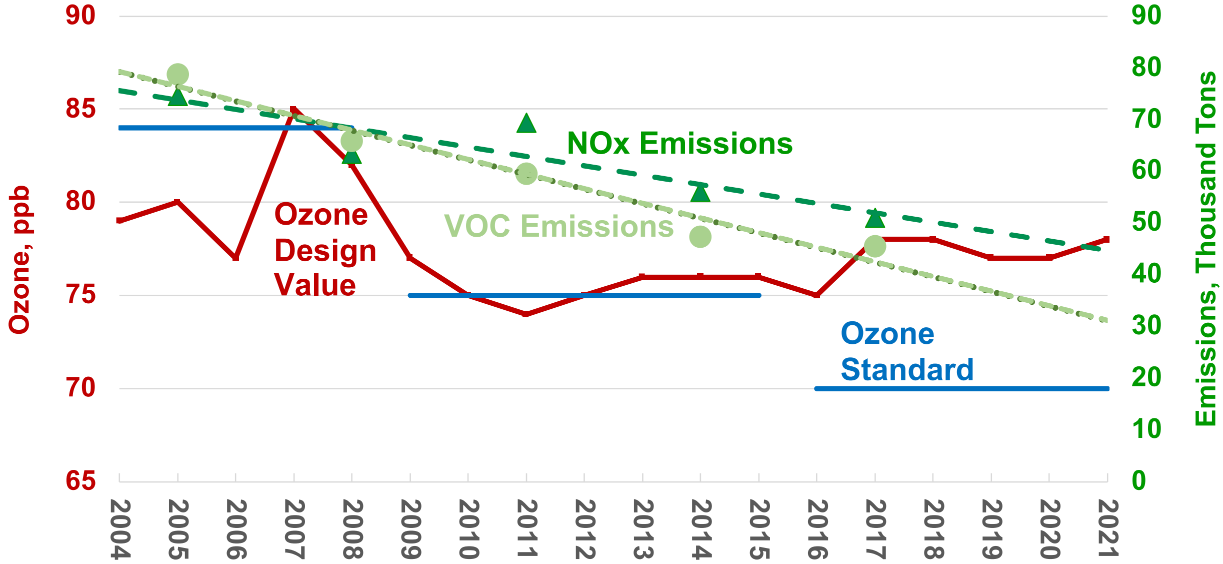

Figure 1. NWF Emissions Trend with Design Value Trends

In the absence of modeling sensitivity studies, we do not know if the NWF is in a VOC-limiting or NOx-limiting regime and the extent to which NOx reductions will reduce ozone if at all. Furthermore, over the period of implementation of these rules, new heavy-duty truck standards and vehicle fleet turnover benefits from new light duty vehicle standards will provide considerable NOx emission reductions. As shown in **Figure 2**, over 60% of local NWF ozone precursor emissions come from mobile sources, and these mobile source vehicle standards will reduce this largest piece of the pie.[43]

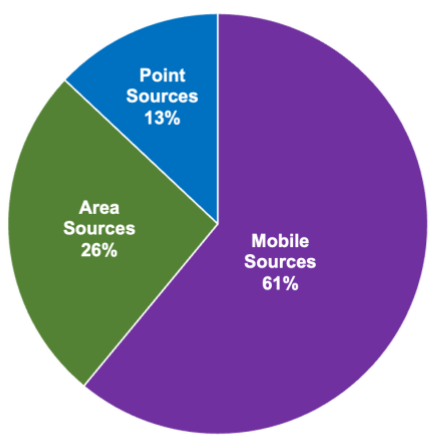

Figure 2. Distribution of Ozone Precursor Emissions (NOx + VOC) in NWF

We understand that UDAQ considers the Boiler Rules as important to achieve future required 3% per year Reasonable Further Progress ("RFP") at Serious nonattainment and above. But if NOx

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Design values obtained from EPA design value reports at https://www.epa.gov/air-trends/air-quality-design-values.

[43] Emissions based on full counties within the NWF and 2017 emission inventory, which as explained above, is the latest data available as of this writing.

reductions will not support the attainment demonstration, it might make more sense to focus future RFP goals on VOC emission reductions for which the NWF must show a 15% reduction while at Moderate nonattainment. Furthermore, the substantial NOx emission reductions obtained from light duty motor vehicle and heavy-duty truck turnover can be counted towards the future RFP goals.

Thus, in the absence of supporting technical information demonstrating that the Boiler Rules will support the required attainment demonstration, it seems prudent to take the time needed to develop rules that will be both technically and economically feasible for all affected facilities.

Conclusion

Overall, the Associations support the Boiler Rules as long as the final rules to be adopted incorporate provisions for affected facilities to conduct case-by-case cost and technical feasibility analyses, incorporate adequate implementation time upon triggering applicability especially where a burner cannot simply be swapped out, and include appropriate definitions, clarifications, and exemptions.

The topic of controlling boiler NOx emissions is complex yet is an important consideration in the pursuit of attainment. But many industrial operations have constraints that affect the ability to use ULNBs. Many other factors influence the feasibility and performance of ULNBs. Understanding that our comments are significant and, in some cases, heavily technical, we offer to meet with you and others at UDAQ to discuss these comments, address any questions you may have, and develop a dialogue about these important factors, all in the pursuit of developing Boiler Rules that are effective as well as technically and economically feasible. If desired, please contact Rikki to coordinate scheduling a meeting.

Sincerely,

Rikki Hrenko-Browning
President, Utah Petroleum Association

Brian Somers
President, Utah Mining Association

cc: Bryce Bird – bbird@utah.gov
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